Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- The net revenues reported are theoretical energy and ancillary net revenues and do not include capacity market revenues.
- Energy net revenues are affected by fuel prices and energy prices. Natural gas prices and energy prices were significantly higher in the first three months of 2014 than in the first three months of 2013, resulting in large increases in net revenues in the first three months of 2014. Eastern natural gas prices were 160.3 percent higher and Western natural gas prices were 81.1 percent higher in the first quarter of 2014 compared to the first quarter of 2013. Energy prices were 131.6 percent higher in the first quarter of 2014 compared to the first quarter of 2013. Eastern natural gas prices were 13.9 percent lower and Western natural gas prices were 1.6 percent higher for the second and third quarters of 2014 compared to the same period of 2013. Energy prices were 2.6 percent lower for the second and third quarters of 2014 compared to the same period of 2013.[1]
- Increases in average net revenues for the first nine months of 2014 were primarily the result of substantial increases in net revenues for the first three months of 2014 as a result of significantly higher energy prices which offset higher fuel costs.
- For the first three months of 2014, energy net revenues increased by 1,444 percent for a new CT, 377 percent for a new CC, 637 percent for a new CP, 9,293 percent for a new DS, 188 percent for a new nuclear plant, 54 percent for a new wind installation, and 33 percent for a new solar installation.
- Average net revenues increased for the second and third quarters of 2014 compared to the same period of 2013 by 7.3 percent for a new CT, increased by 15.9 percent for a new CC, decreased by 1.8 percent for a new CP, decreased by 72.1 percent for a new DS, decreased by 3.9 percent for a new nuclear plant, increased by 6.1 percent for a new wind installation, and increased by 2.2 percent for a new solar installation.
- Average net revenues increased for the first nine months of 2014 by 275 percent for a new CT, 114 percent for a new CC, 202 percent for a new CP, 1,173 percent for a new DS, 58 percent for a new nuclear plant, 28 percent for a new wind installation, and 10 percent for a new solar installation.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

1 Percentage increase is the percentage increase of the average zonal LMP.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. High loads that result in high prices tend to increase energy market net revenues for all unit types. Even a relatively small number of high price hours can significantly increase net revenues. This illustrates the potential role of scarcity pricing as a source of net revenues and also makes it more important to address the appropriate net revenue offset mechanism in the capacity market.

Net Revenue

When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

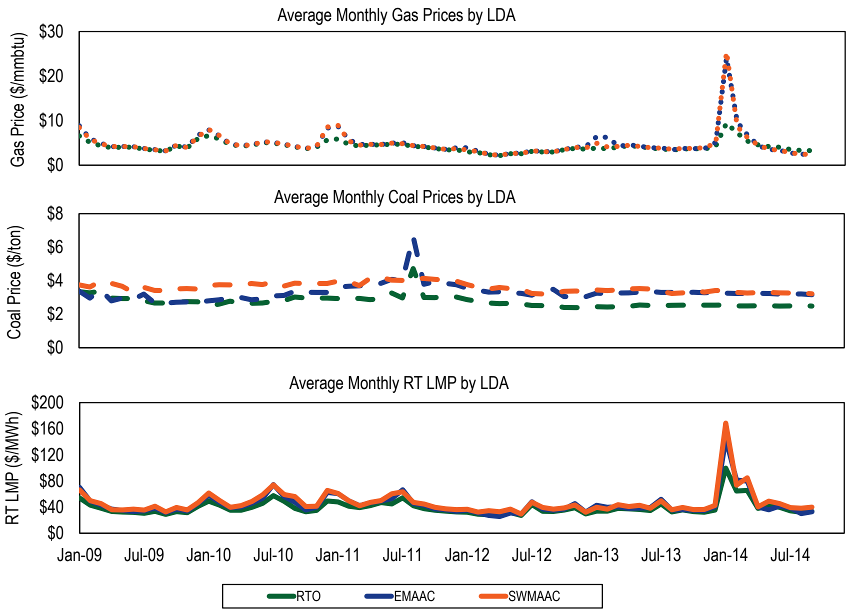
In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Operating reserve (uplift) payments are included when the analysis is based on the peak-hour, economic dispatch model and when the analysis uses actual net revenues.[2]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 47.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, \$58.60 per MWh versus \$39.75 per MWh. Comparing fuel prices in the first nine months of 2014 to the first nine months of 2013, the price of Northern Appalachian coal was 0.5 percent higher; the price of Central Appalachian coal was 2.9 percent lower; the price of Powder River Basin coal was 10.1 percent higher; the price of eastern natural gas was 54.9 percent higher; and the price of western natural gas was 27.0 percent higher.

2 The peak-hour, economic dispatch model is a realistic representation of market outcomes that considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

Figure 7-1 Energy Market net revenue factor trends: 2009 through September 2014



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on this economic dispatch scenario.

Analysis of energy market net revenues for a new entrant includes eight power plant configurations:

- The CT plant has an installed capacity of 410.2 MW and consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant has an installed capacity of 655.7 MW and consists of two GE Frame 7FA.05 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[3]
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two nuclear power units and related facilities using the Westinghouse AP1000 technology.
- The wind installation consists of twenty GE 2.5 MW wind turbines totaling 50 MW installed capacity.
- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4,5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

3 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
4 Hourly ambient conditions supplied by Schneider Electric.
5 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour. Therefore, there is a single offer point and no offer curve.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[6]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[7] Each CT, CC, CP, and DS plant was also given a continuous 14 day planned annual outage in the fall season. Ancillary service revenues for the provision of synchronized reserve service for all four plant types were set to zero. Ancillary service revenues for the provision of regulation service were calculated for the CP only. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour. No black start service capability is assumed for any of the unit types.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CP generators with 30 or fewer operating years.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[8] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[9] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[10]

Operating costs are the short run marginal cost of operations and include fuel costs, emissions costs, and VOM costs.[11,12] Average zonal operating costs in the first nine months of 2014 are shown in Table 7-1.

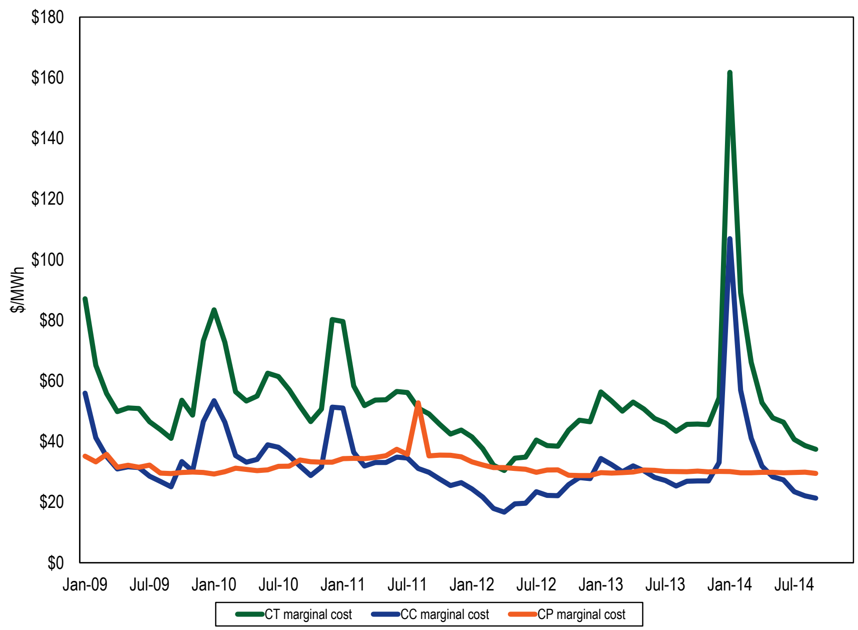
Table 7-1 Average zonal operating costs: January through September, 2014

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$64.45	10,241	$8.59
CC	$39.89	7,127	$1.50
CP	$29.78	9,250	$3.32
DS	$216.67	9,660	$12.50
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A significant increase in gas prices on cold days in January resulted in a corresponding increase in the average zonal operating cost of CTs and CCs in the first nine months of 2014 (Figure 7-2).

6 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
7 Outage figures obtained from the PJM eGADS database.
8 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
9 Gas daily cash prices obtained from Platts.
10 Coal prompt prices obtained from Platts.
11 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
12 VOM rates provided by Pasteris Energy, Inc.

Figure 7-2 Average zonal operating costs: 2009 through September 2014



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM. For this economic dispatch, it was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs. If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day ahead or real time block.

New entrant CT plant energy market net revenues were higher in the first nine months of 2014 as a result of higher energy market prices which more than offset the higher fuel prices. The net revenue increase was the result of an increase in profitable run hours and a number of very high price hours. The impact of very high energy prices varied by zone. The increase in run hours occurred across all zones (Table 7-2).

Table 7-2 Run hours: January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	1,335	2,674	100%
AEP	914	1,470	61%
AP	1,093	1,696	55%
ATSI	1,013	1,703	68%
BGE	1,587	3,395	114%
ComEd	620	884	43%
DAY	898	1,507	68%
DEOK	883	2,718	208%
DLCO	785	1,309	67%
Dominion	1,317	1,646	25%
DPL	1,451	2,915	101%
EKPC	NA	2,654	NA
JCPL	1,491	2,540	70%
Met-Ed	1,238	2,330	88%
PECO	1,183	2,405	103%
PENELEC	1,550	3,481	125%
Pepco	1,532	3,079	101%
PPL	1,171	2,358	101%
PSEG	1,337	2,643	98%
RECO	1,413	2,551	81%

Table 7-3 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through September, 2013 and 2014[13]

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$18,686	$65,291	249%
AEP	$11,603	$53,310	359%
AP	$14,996	$73,123	388%
ATSI	$13,803	$61,854	348%
BGE	$25,497	$92,791	264%
ComEd	$10,072	$34,072	238%
DAY	$11,537	$53,814	366%
DEOK	$10,906	$58,684	438%
DLCO	$12,586	$48,058	282%
Dominion	$18,527	$54,896	196%
DPL	$21,532	$79,746	270%
EKPC	NA	$60,573	NA
JCPL	$23,193	$67,204	190%
Met-Ed	$18,252	$61,592	237%
PECO	$17,783	$63,823	259%
PENELEC	$18,100	$97,180	437%
Pepco	$23,929	$85,225	256%
PPL	$17,943	$61,550	243%
PSEG	$17,833	$59,171	232%
RECO	$20,190	$57,927	187%
PJM	$17,209	$64,494	275%

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM. For this economic dispatch scenario, it was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs.[14] If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day ahead or real time block.

New entrant CC plant energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices which more than offset the higher natural gas prices. The number of run hours for the new entrant CC for the first nine months of 2014 was not significantly different than the run hours for the first nine months of 2013 but profit margins were higher in the first nine months of 2014.

Table 7-4 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$67,902	$151,523	123%
AEP	$53,408	$106,530	99%
AP	$62,620	$134,896	115%
ATSI	$61,237	$121,291	98%
BGE	$81,869	$186,170	127%
ComEd	$36,599	$61,380	68%
DAY	$55,638	$109,053	96%
DEOK	$52,640	$135,719	158%
DLCO	$50,183	$90,588	81%
Dominion	$67,963	$117,614	73%
DPL	$73,935	$166,883	126%
EKPC	NA	$138,031	NA
JCPL	$74,591	$154,888	108%
Met-Ed	$65,164	$140,813	116%
PECO	$63,313	$144,435	128%
PENELEC	$77,855	$192,957	148%
Pepco	$77,997	$178,865	129%
PPL	$63,118	$141,757	125%
PSEG	$67,283	$142,819	112%
RECO	$71,138	$138,674	95%
PJM	$64,445	$137,744	114%

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

New entrant CP plant energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices. The number

13 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
14 All starts associated with combined cycle units are assumed to be hot starts.

of profitable hours in the first nine months of 2014 was significantly greater than the number of profitable hours in the first nine months of 2013.

Table 7-5 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$33,333	$156,476	369%
AEP	$63,464	$135,003	113%
AP	$71,702	$158,894	122%
ATSI	$70,204	$147,947	111%
BGE	$40,323	$187,606	365%
ComEd	$48,494	$107,804	122%
DAY	$73,127	$137,111	87%
DEOK	$64,970	$126,284	94%
DLCO	$17,243	$71,137	313%
Dominion	$86,199	$199,209	131%
DPL	$33,867	$190,074	461%
EKPC	NA	$111,751	NA
JCPL	$38,650	$162,409	320%
Met-Ed	$31,734	$151,305	377%
PECO	$30,480	$154,381	407%
PENELEC	$81,468	$168,945	107%
Pepco	$37,535	$176,294	370%
PPL	$30,409	$151,798	399%
PSEG	$51,343	$183,010	256%
RECO	$56,616	$176,195	211%
PJM	$50,587	$152,682	202%

New Entrant Diesel

Energy market net revenue was calculated assuming that the DS plant was economically dispatched on an hourly basis based on the real-time LMP.

New entrant DS plant energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices which more than offset the higher fuel prices. The number of profitable hours in the first nine months of 2014 was significantly higher than in the first nine months of 2013 for a new entrant DS plant.

Table 7-6 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$1,122	$38,223	3,305%
AEP	$503	$16,786	3,235%
AP	$771	$21,440	2,681%
ATSI	$23,776	$16,495	(31%)
BGE	$2,644	$58,273	2,104%
ComEd	$399	$13,242	3,223%
DAY	$535	$16,611	3,007%
DEOK	$477	$15,688	3,189%
DLCO	$1,198	$15,197	1,168%
Dominion	$1,562	$49,358	3,060%
DPL	$1,125	$44,715	3,874%
EKPC	NA	$16,789	NA
JCPL	$2,079	$38,384	1,746%
Met-Ed	$1,292	$37,217	2,782%
PECO	$1,024	$37,592	3,572%
PENELEC	$1,141	$18,883	1,555%
Pepco	$2,207	$59,878	2,613%
PPL	$1,088	$38,287	3,418%
PSEG	$1,302	$37,889	2,811%
RECO	$2,469	$35,009	1,318%
PJM	$2,459	$31,298	1,173%

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

New entrant nuclear energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices and correspondingly higher margins.

Table 7-7 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$201,009	$338,646	68%
AEP	$176,738	$257,847	46%
AP	$185,986	$284,798	53%
ATSI	$184,807	$271,947	47%
BGE	$218,045	$381,897	75%
ComEd	$159,147	$226,449	42%
DAY	$179,154	$261,071	46%
DEOK	$169,935	$248,818	46%
DLCO	$172,976	$239,409	38%
Dominion	$202,566	$330,659	63%
DPL	$209,085	$364,267	74%
EKPC	NA	$244,774	NA
JCPL	$207,587	$342,907	65%
Met-Ed	$197,535	$326,222	65%
PECO	$196,192	$330,703	69%
PENELEC	$195,363	$297,750	52%
Pepco	$214,271	$368,649	72%
PPL	$195,457	$327,259	67%
PSEG	$222,893	$365,127	64%
RECO	$228,625	$358,855	57%
PJM	$195,651	$308,403	58%

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing wind units in the zone were generating power in that hour.

New entrant wind energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices and correspondingly higher margins. Wind net revenues did not increase as much as other technology types because wind is not dispatchable in response to higher prices.

Table 7-8 Energy Market net revenue for a wind installation (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
ComEd	$103,483	$128,975	25%
PENELEC	$110,020	$145,550	32%

New Entrant Solar Installation

Energy market net revenue for a solar installation located in the PSEG Zone was calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing solar units in the zone were generating power in that hour.

New entrant solar energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices and correspondingly higher margins. Like wind, solar net revenues did not increase as much as other technology types because solar is not dispatchable in response to higher prices.

Table 7-9 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
PSEG	$428,020	$470,617	10%